UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
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OCT 3 1 2019

ENFORCEMENT &
COMPLIANCE ASSURANCE
DIVISION

Reply To: 20-C04

FOR SETTLEMENT PURPOSES ONLY

CERTIFIED MAIL – RETURN RECEIPT REQUESTED

Ms. Shirley Yap
General Manager
Equilon Enterprises LLC
Doing business as Shell Oil Products, US
P.O. Box 622
Anacortes, Washington 82221

Re: Clean Air Act Section 112(r) Compliance at Shell's Puget Sound Refinery

Dear Ms. Yap:

In follow-up to conversations between Shell legal counsel Cisselon Nichols and Region 10 legal counsel Julie Vergeront, I am writing regarding the Puget Sound Refinery located at 8505 South Texas Road in Anacortes, Washington ("Puget Sound Refinery"), which is owned by Equilon Enterprises LLC and does business under the name of Shell Oil Products, US ("Shell"). The purpose of this letter is to provide a summary of the Clean Air Act Section 112(r) violations and areas of concern that the U.S. Environmental Protection Agency (EPA) has identified at the Puget Sound Refinery and to offer Shell the opportunity to discuss this matter with EPA prior to the initiation of formal enforcement.

Enclosed is a Summary of the Alleged Violations and Areas of Concern, which provides information about EPA's allegations. The identified violations and areas of concern arose out of the February 20, 2015, release from the East flare at the Puget Sound Refinery during a facility turnaround, and EPA's follow up investigation, including EPA's August 2015 inspection of the Puget Sound Refinery. The February 20, 2015, release resulted in complaints from over 500 individuals in the area.

In general, EPA favors prefiling discussions, which help ensure that we have all relevant information and may lead to resolution that avoids the time and expense of litigation. If you wish to set up a meeting to discuss this matter, please have your legal counsel contact Julie Vergeront in the Office of Regional Counsel at (206) 553-1497 within 14 days of receipt of this letter. EPA is willing to meet with Shell at our Seattle office or by conference call. If Shell is interested in such a meeting, Shell should come prepared to discuss all relevant information and provide supporting documentation to support the company's viewpoint on the alleged violations and concerns.

If we do not hear from Shell within 14 days, EPA will take that as an indication that Shell does not wish to engage in prefiling negotiations, in which case EPA intends to move forward unilaterally.

Thank you for your prompt attention to this important matter.

Sincerely,

Morgan J. Jencius

Morgan Jencius, Branch Chief
Air & Land Enforcement Branch

Enclosures
1. Summary of Alleged Violations and Areas of Concern

cc: Ms. Cisselon Nichols
Shell Oil Company

Ms. Aselda Thompson
Shell Oil Company

<u>Summary of Alleged Violations and Areas of Concern</u>
Shell Puget Sound Refinery

This document summarizes the chemical accident prevention violations under Section 112(r)(7) of the Clean Air Act (CAA) identified by a U.S. Environmental Protection Agency, Region 10 (EPA) investigation of the Shell Puget Sound Refinery located at 8505 South Texas Road in Anacortes, Washington (Puget Sound Refinery), as well as additional areas of concern. The Puget Sound Refinery is owned by Equilon Enterprises LLC and does business under the name of Shell Oil Products, US (Shell).

Section 112(r)(7) of the CAA, 42 U.S.C. § 7412(r)(7), and its implementing regulations at 40 C.F.R. Part 68 require the owner or operator of a stationary source at which a regulated substance is present at more than a threshold quantity to prepare and implement a risk management plan (RMP) and program to detect and prevent or minimize accidental releases of such substances from the stationary source and to provide prompt emergency response to any such releases in order to protect human health and the environment.

Shell first submitted a RMP for the Puget Sound Refinery to EPA on June 21, 1999 and has submitted numerous updates to that plan since that time, most recently on April 22, 2015. Shell's RMP for the Puget Sound Refinery states that it has had greater than the 10,000-pound threshold quantity (TQ) of anhydrous ammonia and/or greater than the 10,000-pound TQ of a flammable mixture of one percent or greater by weight in fourteen covered processes. Because each of these covered processes are subject to the Occupational Safety and Health (OSHA) Process Safety Management (PSM) requirements in 29 C.F.R. § 1910.119, each covered process is classified as a Program 3 facility under 40 C.F.R. § 68.10(d).

As facility with Program 3 covered processes, in addition to submitting a RMP as provided in 40 C.F.R. § 68.12(a) and §§ 68.150 through 68.185 that includes a registration that reflects all covered processes, 40 C.F.R. § 68.12(d) requires that the Puget Sound Refinery develop and implement a management system as provided in 40 C.F.R. § 68.15; conduct a hazard assessment as provided in 40 C.F.R. §§ 68.20 through 68.42; implement the prevention requirements of 40 C.F.R. §§ 68.65 through 68.87; develop and implement an emergency response program as provided in 40 C.F.R. §§ 68.90 through 68.95; and submit as part of the RMP the data on prevention program elements for Program 3 processes as provided in 40 C.F.R. § 68.175.

EPA has identified the following violations of the RMP and risk management program requirements of Section 112(r)(7) of the Clean Air Act, 42 U.S.C. § 7412(r)(7), and 40 C.F.R. Part 68

1. *<u>Failure to Submit a Single RMP that Includes All Covered Processes</u>*

40 C.F.R. § 68.150(a) requires the owner or operator to submit a single RMP that includes the information required by §§ 68.155 through 68.185 for all covered processes. 40 C.F.R. § 68.3 defines "process" as any activity involving a regulated substance including any use, storage, manufacturing, handling, or on-site movement of such substances, or a combination of these activities. For purposes of this definition, "any group of vessels that are interconnected, or separate vessels that are located such

that a regulated substance could be involved in a potential release, shall be considered a single process." A "covered process" is a process that has a regulated substance present at more than a threshold quantity, as determined under 40 C.F.R. § 68.115. 40 C.F.R. § 68.3.

The Puget Sound Refinery includes a flare system that burns waste gases and vapors that are generated but not used during production. The flare system is comprised of three connected flares identified as the North, South, and East flare and a single flare gas recovery unit (FGR) that is shared by all three flares during normal operating conditions (the flares and the FGR are referred to here as the "Flare System").

Shell has not included the Flare System in its RMP, either as a separate covered process or as part of another covered process, as required by 40 C.F.R. § 68.150(a). The Flare System meets the definition of "process" in 40 C.F.R. § 68.3 because it is comprised of vessels that are interconnected with other vessels that are part of covered processes, such as the Alkylation Unit #1 and #2, Catalytic Reformer Unit #1 and #2, Crude Distillation Unit, Hydrotreating Unit #1, #2 and #3, and Fluid Catalytic Cracking Unit /Gas Recovery Unit. Shell could also identify the Flare System as a separate covered process in its RMP if Shell acknowledges that it is a "covered process." EPA has calculated that the Flare System has the capacity to hold, and during releases does hold, well over 10,000 pounds of a regulated flammable substances in a mixture, thus meeting the definition of a "covered process" as a separate process.

In addition to revising its RMP to cover the Flare System, as part of any settlement, EPA expects Shell to demonstrate that it is meeting all other requirements of Part 68 with respect to the Flare System as part of another covered process or as a separate covered process.

2. *Failure to Adequately Define Offsite Impacts in a Hazard Assessment*

40 C.F.R. § 68.30(b) provides that the presence of institutions (schools, hospitals, prisons), parks and recreation areas, and major commercial, office, and industrial buildings shall be noted in a facility's RMP.

The RMP for the Puget Sound Refinery does not note major commercial, office, or industrial areas as receptors in its RMP in describing the Alternative Relief Scenario for flammables, as required by 40 C.F.R. § 68.30(b). EPA has identified at least two (the Linde and Air Liquide hydrogen plants) and possibly three (Chemtrade, depending on the center of the release point) neighboring industrial facilities that are within the 0.43-mile radius from the butane storage spheres that were used as the point of release in the Alternative Relief Scenario for flammables.

3. *Failure to Compile All Written Process Safety Information*

- 40 C.F.R. § 68.65(c)(1)(iv) requires that process safety information pertaining to the technology of the process include safe upper and lower limits for such items as temperatures, pressures, flows or compositions. During the August 2015 inspection, EPA observed that the "reason for value" explanation of the emergency (critical high) alarm pressure setting for the identified pressure relief valve (PRV) for Ammonia Tank 90-C009 was not accurate. The emergency alarm is set at 200 pounds per square inch gauge (psig), which is 20% below 250 psig, and not 12% below, as stated in the variable table that contains the process safety information for this unit.

- 40 C.F.R. § 68.65(d)(1)(ii) requires that process safety information pertaining to the equipment in the process include piping and instrumentation diagrams (P&IDs). During the August 2015 inspection, EPA identified numerous instances in which P&IDs of the following covered processes did not accurately reflect the design of covered process equipment as installed: (1) the ammonia storage tank (90-C009), Boiler House/Cogeneration; (2) HTU #2 – Charge/Effluent Exchangers (11E-101 A/B); and (3) butane storage sphere TK-102. See Attachment A for the discrepancies identified during the August 2015 inspection.

4. *Failure to Implement Written Operating Procedures and Management of Change Procedures*

40 C.F.R. § 68.69(a) requires the owner or operator to develop and implement written operating procedures that provide clear instructions for safely conducting activities involved in each covered process consistent with process safety information and that address specified elements, including normal shutdowns.

40 C.F.R. § 68.75(a) requires the owner or operator to establish written procedures to manage changes to process chemicals, technology, equipment, and procedures; and changes to stationary sources that affect a covered process. The procedures must assure that certain considerations, such as the impact on safety and health and necessary modifications to operating procedures, are addressed prior to making any change. 40 C.F.R. § 68.75(b).

On February 20, 2015, Shell failed to follow its written procedures in the East Flare Shutdown Procedure, 19FLARETA004, when shutting down the East flare during a partial shutdown/turnaround operation at the Puget Sound Refinery. In addition, Shell was unable to produce documentation establishing that it followed its management of change procedures when operators deviated from the standard shutdown. Operators skipped several steps in the procedure, causing an un-combusted vapor release that impacted more than 500 people in the neighboring communities.

5. *Failure to Develop and Implement Mechanical Integrity Procedures*

40 C.F.R. § 68.73(b) and (d)(2) require the owner or operator to establish and implement written procedures to maintain the on-going integrity of specified process equipment that follow recognized and generally accepted good engineering practices.

- Shell failed to establish and implement written procedures to maintain the on-going integrity of underground piping at the Puget Sound Refinery that follow recognized and generally accepted good engineering practices. During the August 2015 inspection, Shell was unable to produce written maintenance procedures for the inspection and testing of underground piping. EPA was provided PEI POL000 (PEI Inspection Requirements), PEI POL 074 (Piping Deadleg Inspection), and PEI POL 130 (Wharf Piping Inspection) as procedures that addressed underground piping. Of these, only the Wharf Piping Inspection procedure, PEI POL 130, mentions underground piping, stating on page 2 that "segments of the underground transfer pipeline shall be exposed (daylighted) and examined by radiograph by PEI." This procedure does not address other lengths of piping located on-site or the requirements found in API 570, Piping Inspection Code: Inservice Inspection, Rating, Repair, and Alteration of Piping Systems (API 570), for underground piping inspections. Shell sent EPA a document dated August 25, 2015, which stated that Shell implements the requirements in API 570 for underground piping inspections using their Soil to Air Interface inspection program. This simple statement does not meet the requirements of 40 C.F.R. § 68.73(b) and (d)(2) to establish and implement written procedures to maintain the on-going integrity of underground piping that follow recognized and generally accepted good engineering practices.

- During the August 2015 inspection, Shell was unable to produce written procedures for Shell's new internal risk-based inspection tracking software for process equipment, including process equipment identified in 40 C.F.R. § 68.73(a) for which written mechanical integrity procedures are required. At the time of the inspection, Shell was changing its mechanical integrity tracking software process from API's risk-based inspection scheme to Shell's new internal risk-based inspection scheme using a ten-year implementation plan. The API risk-based inspection tracking software previously used by Shell produces reports with inspections schedules on process equipment based on information entered by Shell personnel manually (BPG INSP-20). EPA understands that Shell's new internal risk-based inspection tracking software for the Puget Sound Refinery extracts information from the inspection data management software on process equipment and is designed to be more conservative. At the time of the inspection, EPA understood that the transition to the new inspection tracking system began on December 31, 2014 and was expected to be completed by December 31, 2025, using scheduled maintenance turnarounds to transition inspection process equipment history to Shell's new internal risk-based inspection system. At the time of the inspection, Shell had no written procedures for how to use its new internal risk-based inspection tracking software to manage mechanical integrity inspections. In contrast, Shell had detailed procedures for implementing its API risk-based inspection mechanical integrity program.

6. *Failure to Implement Written Procedures to Manage Changes*

40 C.F.R. § 68.75(a) requires the owner or operator to establish written procedures to manage changes to process chemicals, technology, equipment, and procedures; and changes to stationary sources that affect a covered process. The procedures must assure that certain considerations, such as the impact on safety and health and necessary modifications to operating procedures, are addressed prior to making any change.

During the August 2015 inspection, Shell was unable to demonstrate that it followed its management of change procedures when it began to change its tracking software process for inspections from the API risk-based inspection system to Shell's new internal risk-based inspection system.

Additional Areas of Concern

Concern 1: Shell's Offsite Consequence Analysis for toxics relied on a distance to endpoint radius calculation of 1.5 miles with an estimated residential population of 440 impacted by the modeled release. Using EPA's RMP*Comp methodology results in a distance to endpoint radius calculation of 5.4 miles and an estimated residential population of 20,318 impacted by the modeled release. Given the substantial difference between these two calculations, EPA requests an explanation of the basis for Shell's calculations.

Concern 2: During the August 2015 inspection, the inspection team observed that the PRV vent pipes on the alkylation spent acid tanks vent vapors at grade of the tanks and discharge horizontally inside of the tank berm. While in close proximity to PRV 5035 in this area, the inspection team smelled a strong hydrocarbon odor, which caused an inspector to briefly choke on the inhaled vapors. The location of the vent pipes poses a potentially hazardous condition to workers by inhalation or a potential explosive atmosphere. See 40 C.F.R. § 68.65(d)(2); see also 29 C.F.R. § 1910.106(b)(2)(vi)(b); API 2000, November 2009; NFPA 30, 2015 Edition (addressing similar situations where vent pipes are adjacent to buildings and public ways).

Concern 3: The EPA inspection team noted several respects in which the written operating procedures for the ammonia storage tank (90-C009) may not provide clear instructions for safely conducting activities for this covered process (see 40 C.F.R. § 68.69(a)):

(a) During an emergency (critical high) alarm for 90PI238, the procedure directs the outside operator to open and stay stationed at the pressure control valve, PCV18 bypass, which appears to contradict the console operator instruction to assume the PRV and/or bypass is open, which would result in an unsafe situation for the outside operator if the PRV is relieving and releasing ammonia;
(b) Ammonia Tank Shutdown procedure, 90COGTO026 does not appear to provide a clear distinction between the two 2-inch block valves on the unloading line/ammonia fill line to adequately inform the operator which valve to open in step 2.7 and which valve to slowly throttle in step 2.8. In addition, the same line is referred to differently in these two steps ("unloading line" versus "ammonia fill line"); and
(c) Ammonia Unloading procedure, 90COGNO030 does not instruct the operator to ensure that the 1-inch vent on the unloading line is closed to prevent ammonia from venting to the atmosphere during truck unloading.

Concern 4: The operating procedures for ammonia storage tank (90-C009) appear vague with respect to personal protective equipment, stating "Use proper PPE including supplied air when venting ammonia to the atmosphere." The procedure does not identify what personal protective equipment other than supplied air respirators that must be available and worn when performing the shutdown.
See 40 C.F.R. § 68.69(a)(3)(ii).

Concern 5: During the August 2015 inspection, Shell provided inspection and testing data on pipe circuit HTU220-04 associated with the hydrotreater unit flare knock-out pot. The documents provided showed that ultrasonic testing to measure the thickness of pipe circuit HTU220-04 was conducted in December 2001 and February 2014. Shell Risk Based Inspection Implementation, BPG INSP-20, Rev 2, Dated 2/28/08, pg. 83, requires the risk-based inspection interval to be at the projected half-life or the maximum intervals suggested in API-570, Table 6-1 (now Table 2). In Table 2, pipe circuit HTU220-04 is shown as a type Class 1 pipe circuit with a maximum inspection interval of five years, although EPA acknowledges that this interval may have changed in Shell's new internal risk-based inspection system, which may now be in use for this equipment. Given that the five-year time interval for testing was not met prior to 2014, we request confirmation that ultrasonic testing on this unit was conducted by February 2019 or the currently applicable inspection interval to demonstrate that the frequency of inspections and tests of this process equipment is consistent with applicable manufacturers' recommendations, good engineering practices, and more frequently if determined to be necessary by prior operating experience, as required by 40 C.F.R. § 68.73(d)(3).

Attachment A
to
Summary of Alleged Violations and Areas of Concern
Shell Puget Sound Refinery

P&ID Discrepancies Identified during EPA Inspection

(1) Ammonia Storage Tank (90-C009) P&ID Field Verification (P&ID drawing number 90-DA-0640 FR.8, (PSR03980))

- The inspection team observed the vapor return line (3"-90-NAH-2002-J312) from the vaporizer (90-P010) to the ammonia storage tank (90-C009) had steam tracing. The P&ID did not indicate steam tracing on this line.
- The inspection team observed a manual valve upstream of the local pressure indicator (PI) on the top of the vaporizer (90-P010). The P&ID did not indicate this manual valve.
- The P&ID indicates the vaporizer vapor return line (3"-90-NAH-2002-J312) has a pressure safety valve (PSV) upstream of where the vapor return line connects to the top of the ammonia storage tank (PSV 14). The inspection team observed a manual valve that was car sealed open upstream of PSV 14, but the P&ID does not indicate this manual valve.
- The P&ID indicates that the 2" manual valve closest to the truck connection point on each of the ammonia liquid fill line (2"-90-NAH-2003-J312) and the ammonia vapor return line (2"-90-NAH-2001-J312) are car sealed closed. The inspection team did not observe car seals on either of these valves.
- The P&ID indicates an additional truck unloading connection point branching off of the primary ammonia liquid fill line (2"-90-NAH-2003-J312). However, the inspection team observed that this connection point was capped with a local pressure indicator assembly with a manual valve, which was not indicated on the P&ID. Additionally, the inspection team observed that the 1" manual valve on the bypass line connecting the truck unloading connection line to the pressure relief line to be car sealed closed. The P&ID did not indicate this valve to be car sealed closed.
- The P&ID indicates the ammonia tank has an instrumented level transmitter (LIT 13). However, the inspection team observed that this instrumented level transmitter also had a local level indicator (LI) installed on the tank. The P&ID did not indicate a local LI.
- The P&ID indicates the ammonia tank has a thermowell (TW 13) and local temperature indicator (TI 13) on one of the heels of the tank. The inspection team did not identify TW 13 or TI 13 on the tank.
- The inspection team observed two manways installed on the tank: one on one of the heels of the tank and one on the top of the tank. The P&ID does not indicate either of these two manways.
- The P&ID indicates a three-way valve installed on top of the tank, which has flow options to two different PSVs: PSV 17 and PSV 18. The refinery operator

escorting the inspection team explained that the three-way valve is turned to allow relieving flow to one of the two PSVs at a time. The inspection team observed this three-way valve to be car sealed, but the P&ID does not indicate the valve is car sealed.

- The inspection team observed pressure control valve (PCV) 18 to have steam tracing. The P&ID does not indicate that PCV 18 has steam tracing.
- The inspection team observed a bleeder valve on the PCV 18 bypass line. The P&ID does not indicate this bleeder valve.
- The inspection team observed a bleeder valve upstream of PCV 18. The P&ID does not indicate this bleeder valve.
- The P&ID indicates that the ammonia monitoring detectors can trigger a visual alarm (AL 13) and an audible alarm (a horn) (AI 13). The refinery operator escorting the inspection team explained, however, that the ammonia tank only has a visual alarm (a red beacon light) and does not have a horn. The inspection team did observe the red beacon light.

(2) HTU #2 – Charge/Effluent Exchangers (11E-101 A/B and E/F) P&ID (portions of P&ID drawing numbers 11-DA-008 FR.4 (PSR04583) and 11-DA-008 FR.5 (PSR04584))

11E-101 E/F

- The inspection team observed an instrumented temperature element (TE 289) and a drain line to a process sewer on the reactor feed immediately upstream of the 11E-101E exchanger. The P&ID for this exchanger (11-DA-008 FR.4; PSR04583) does not indicate this TE or drain line. It is possible these items may be on an adjoining P&ID.

11E-101 A/B

- The P&ID (11-DA-008 FR.5; PSR04584) indicates that the 11E-101A reactor charge bypass line, bypassing the flow control valve FV 4, has a local pressure indicator . The inspection team observed a bleeder valve in place of the local PI.
- The P&ID (11-DA-008 FR.5; PSR04584) indicates that the HP condensate line (2"-11-SC-14-J12) can be connected to a swing ell to connect HP condensate flow into the reactor charge inlet to 11E-101A and the reactor effluent outlet from 11E-101A. The inspection team did not observe a swing ell in place; it appeared the swing ell had been disconnected.
- The inspection team observed a bleeder valve on the reactor effluent outlet from 11E-101A (10"-11-OH-25-J64) immediately upstream of the 10" manual valve and spectacle. The P&ID (11-DA-008 FR.5; PSR04584) does not indicate this bleeder valve.
- The P&ID (11-DA-008 FR.5; PSR04584) indicates the 2" manual valve on the relief line to the flare from the reactor effluent outlet from 11E-101A (2"-11-VF-20-J64) is blinded. The inspection team did not observe a blind on this line.

- The P&ID (11-DA-008 FR.5; PSR04584) indicates the HP condensate line (2"-11-SC-14-J12) can drain into a process sewer. The inspection team observed this process sewer drain to be closed-off with a cap.
- The inspection team observed a bleeder valve downstream of the 2" manual valve on the relief line to the flare from the reactor charge inlet to 11E-101A (2"-11-VF-16-J64). The P&ID (11-DA-008 FR.5; PSR04584) does not indicate this bleeder valve.

(3) Butane Storage Sphere (TK-102) P&ID (portions of P&ID drawing number 21-DA-0250 FR.7 (PSR03983) of mixed butane storage sphere TK-102)

- The inspection team observed a manway at the bottom of TK-102. The P&ID does not indicate this manway.
- The inspection team observed a bleeder valve on each of the two pressure relief lines at the top of TK-102 for PSVs 456 and 457: both bleeder valves were upstream of the PSVs and downstream of the 6" car-sealed open valves. The P&ID does not indicate these two bleeder valves on the relief lines.
- The inspection team observed a bleeder valve on line 4"-21-0-159-J050B, in-between the 4" car-sealed open valve and the 4" check valve. The P&ID does not indicate this bleeder valve.